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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Modernizing Electricity Market Design **[Docket No. AD21-10-000]**

Notice Inviting Post-Technical Conference Comments

On September 14, 2021 and October 12, 2021, the Federal Energy Regulation Commission (Commission) convened staff-led technical conferences to discuss energy and ancillary services markets in the evolving electricity sector.

All interested persons are invited to file initial and reply post-technical conference comments on the topics in Parts I and II below, which contain the questions posed in each technical conference agenda. Commenters may reference material previously filed in this docket, including the technical conference transcripts, but are encouraged to avoid repetition or replication of previous material. Commenters need not answer all of the questions, but commenters are encouraged to organize responses using the numbering and order in the below questions. Initial comments must be submitted on or before **February 4, 2022**. Reply comments must be submitted on or before **March 7, 2022**.

I. Comments on Supplemental Notice for September 14, 2021 Technical Conference

We are seeking comments on the topics discussed during the technical conference held on September 14, 2021, including responses to the questions listed in the Supplemental Notice issued in this proceeding on September 13, 2021 in accordance with the deadlines and other guidance above. The questions from the agenda are included below.

Panel 1: Understanding the Need for Additional Operational Flexibility in RTO/ISO Energy and Ancillary Services Markets

1. RTOs/ISOs and other industry experts generally agree that power systems will require greater flexibility from system resources in the future.[1] What operational capabilities or services will be most valuable to RTO/ISO operators in the future as the resource mix and net load profile changes and why? Is there a desirable reaction time, sustained performance duration, etc. expected from a resource?

2. To what extent will the “traditional ancillary services” defined in Order No. 888[2]

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[1] *See, e.g.*, CAISO, *Day-Ahead Market Enhancements Revised Straw Proposal*, at 7 (June 2020); SPP, *Uncertainty Product Whitepaper*, at 6 (Mar. 2020); NYISO, *Reliability and Market Considerations For A Grid in Transition*, at 8-9 (Dec. 2019).

[2] Order No. 888 required the following six ancillary services be offered in an open access transmission tariff: (1) Scheduling, System Control and Dispatch Service; (2)

and existing energy market designs continue to ensure reliability as the resource mix changes in RTO/ISO markets in the future?

   a. Will traditional ancillary services provide the appropriate types and adequate quantities of operational flexibility RTOs/ISOs need to manage both expected (e.g., reasonably predictable) and unexpected (e.g., inherently uncertain and captured in forecast errors) variability in net load?

   b. Will existing RTO/ISO energy and ancillary services market designs that generally compensate certain traditional ancillary services resources based on the opportunity cost of foregone energy sales – for example, spinning and non-spinning reserves - give resources a sufficient economic incentive to offer their flexible capabilities to the RTO/ISO?

3. How should RTOs/ISOs define the system's need for operational flexibility, now and in the future?

   a. To what extent is operational flexibility needed on a bi-directional basis (i.e., both up and down) versus a unidirectional basis (i.e., only up or down)?

   b. How do these needs compare to the services provided by traditional ancillary service products?

4. Could variable energy resources or new resource types (e.g., storage, hybrid, and co-located resources) be operated or dispatched differently from the status quo to provide greater operational flexibility to the RTO/ISO, if so, how? Given the evolving resource mix, are the current eligibility requirements for each resource type to provide ancillary services appropriate?

Panel 2: Revising Existing Operating Reserve Demand Curves (ORDCs) to Address Operational Flexibility Needs in RTOs/ISOs

1. Contingency reserves are provided by existing 10- and 30-minute reserve products and are designed to ensure the system can recover from a contingency (e.g., a generator or transmission outage). How will the procurement of additional contingency reserves help RTO/ISO operators manage routine operational flexibility needs (e.g. needs driven by net load variability and uncertainty)?

2. What are the benefits of procuring contingency reserves beyond the minimum reserve requirement through a given ancillary service product?

   a. If employing such a method, how should RTOs/ISOs determine the market's demand for contingency reserves (both the quantity and

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Reactive Supply and Voltage Control from Generation Sources Service; (3) Regulation and Frequency Response Service; (4) Energy Imbalance Service; (5) Operating Reserve - Spinning Reserve Service; and (6) Operating Reserve - Supplemental Reserve Service. Order No. 888, FERC Stats. and Regs. ¶ 31,036, at 31,703 (1996).

willingness to pay) beyond the minimum reserve requirement of a given contingency reserve product?

   b. What principles should RTOs/ISOs follow if they consider revising the shape of the ORDC for a given contingency reserve product (e.g., introducing additional steps or graduation to the ORDC curve)? For example, should the willingness to pay for such additional reserves be based on the Value of Lost Load times the loss of load probability with a given quantity of the reserve product associated with the ORDC, the cost of actions operators would take to procure additional reserves, or some other valuation method? How should customer willingness to pay be incorporated?

3. Reserve shortage prices are administratively determined penalty factors invoked when the system falls below the minimum requirement of one or more reserve products. To what extent can higher reserve shortage prices inform investment decisions and reflect the value of flexible resource capabilities?

   a. What principles should RTOs/ISOs follow if they consider revising the shortage price associated with the ORDC of a given contingency reserve?

   b. How should the shortage prices of individual contingency reserve products be determined? For example, should the shortage prices reflect the marginal reliability value of each individual reserve product? How should customer willingness to pay be incorporated?

   c. How should shortage pricing be implemented when the system is short both 10- and 30-minute reserves? Does establishing shortage prices based on the marginal reliability value of each contingency reserve product that is in shortage ensure that adding the shortage prices reflects the combined reliability impact of being short of those reserve products?

   d. Do differences in shortage prices across regions present operational challenges today? Is there an expectation that such differences could present operational challenges in the future as the resource mix and load profiles change? Is there a need to better align shortage pricing across RTOs/ISOs, and if so, what principles should be considered in doing so?

4. To what extent do RTOs/ISOs use contingency reserves to manage non-contingency related operational uncertainties (e.g., expected and unexpected net load variability)? If such reserves are used for this purpose, should this alter an RTO/ISO's approach to establishing the maximum height and shape of the ORDC? Under such approaches, how do prices in the ORDC appropriately reflect the marginal reliability value contingency reserves provide?

5. Is there a particular point at which procuring reserves beyond the minimum reserve requirement can reduce or conflict with the objectives of shortage prices? What is an appropriate balance between raising shortage prices and procuring reserves beyond the minimum reserve requirement given that procuring additional

reserves can reduce the probability of the RTO/ISO experiencing a shortage?

Panel 3: Creating New Products to Address Operational Flexibility Needs in RTOs/ISOs

1. Ramp products, as distinguished from traditional ancillary service products, are relatively new ancillary services that are in place in CAISO and MISO, and approved for implementation in SPP. Ramp products are generally *not* designed to address contingencies[3] but are instead a mechanism to position the system efficiently to meet forecasted ramping needs in future intervals at least cost on an expected basis.

    a. RTO/ISO ramp products procure ramp on a short-term basis (e.g., for intervals of 10 or 15 minutes), but longer-term ramp products are being considered. For example, SPP is considering a longer-term ramp product[4] and the California Department of Market Monitoring has advised CAISO to consider a longer-term ramp product.[5] What drives the need for, and what are the benefits of, a longer-term ramp product compared to the existing shorter-term ramp products or traditional reserve products?

2. Will establishing reserve and ramp prices based on foregone energy revenues provide such signals in a system with a high penetration of variable energy resources, many of which have low or zero marginal costs?

    a. If not, what other options exist to ensure sufficient compensation for resources providing reserve and ramp capability?

    b. Historically, the prices for the ramp products in CAISO and MISO have often been zero. Are ramp prices expected to increase over time as system needs evolve? If so, what specific conditions might cause ramp prices to increase? Will any expected ramp price increases be sufficient to incent and appropriately compensate the ramp capability RTOs/ISOs and others expect will be needed due to the changing resource mix?

3. CAISO is considering a Day-Ahead Energy Market Enhancement proposal that

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[3] For example, ramping products are not designed to be substitutable with the reserve products used for managing contingencies. *See e.g.* CAISO, *Flexible Ramping Products Straw Proposal* at 7, 10 (Nov. 1, 2011) http://www.caiso.com/Documents/FlexibleRampingProductStrawProposal.pdf; Sw. Power Pool, Inc., Filing, Docket No. ER20-1617-000, at 13 (filed Apr. 21, 2020).

[4] *See* Sw. Power Pool, Inc., "RR449 – Uncertainty Product" (July 27, 2021), https://www.spp.org/Documents/64125/rr449.zip. *See also* Sw. Power Pool, Inc., *Uncertainty Product Prototype Design Whitepaper* (Mar. 13, 2020).

[5] CAISO Department of Market Monitoring, Comments on Issue Paper on Extending the Day-Ahead Market to EIM Entities, at 8 (Nov. 22, 2019).

seeks to ensure that the day-ahead market clears sufficient resources to address expected net load variability and uncertainty that arises between day-ahead and real-time. What are the expected advantages and disadvantages of revising the day-ahead market construct in this way to procure additional operational flexibility?

4. The Electric Reliability Council of Texas, Inc. (ERCOT) has proposed to procure fast-responding, limited duration products to address primary frequency control issues associated with declining system inertia.[6] CAISO also intends to initiate a stakeholder process to discuss, among other options, compensating internal resources for the provision of primary frequency response.[7] What are the merits of such reforms and should they be considered in other regions?

5. What other new products not yet discussed at this conference, do you think could increase operational flexibility in RTOs/ISOs?

    a. Can capacity markets or other, potentially new, "intermediate" forward market constructs that clear between existing capacity market auctions and the day-ahead timeframe help ensure that RTO/ISO operators have sufficient operational flexibility in real time?

    b. For example, can a new shorter-term forward market to procure expected operational flexibility needs held closer to the delivery period (e.g., three months ahead as opposed to three years ahead) and with a more granular delivery period than the annual capacity market (e.g., monthly or seasonal delivery period, or a delivery period based on the hours of an RTO/ISO's morning or evening ramp as opposed to the annual delivery period of most RTO/ISO capacity markets) help ensure that RTO/ISO operators have sufficient operational flexibility in real time?

Panel 4: Market Design Issues and Tradeoffs to Consider in Reforms to Increase Operational Flexibility in RTO/ISO Energy and Ancillary Services Markets

1. To date, most RTOs/ISOs have pursued new ramping products or ORDC reforms, but not both. What are the tradeoffs to consider when deciding between these two approaches and how do they interact? Should these two types of reforms be considered substitutes or complements? Does the opportunity-cost-based method of establishing reserve and ramping product prices send appropriate long-term signals to resources to invest in or maintain flexible capabilities?

2. Some entities have observed that offering additional resource capabilities into energy and ancillary services markets may not be in the financial interest of

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[6] *See* Pengwei Du et al., *New Ancillary Service Market for ERCOT*, IEEE Access Volume 8, https://ieeexplore.ieee.org/abstract/document/9208672.

[7] *See* CAISO, *2021 Three-Year Policy Initiatives Roadmap and Annual Plan*, http://www.caiso.com/InitiativeDocuments/2021FinalPolicyInitiativesRoadmap.pdf.

certain resources because doing so could lower energy prices by either avoiding scarcity conditions or obviating the need to commit more expensive units, and thus reduce their expected energy and ancillary services markets revenue. Are such incentive issues relevant in the context of reforming energy and ancillary services markets to address operational flexibility needs? If so, how should such issues be addressed?

3. What other market design issues and tradeoffs should RTOs/ISOs, stakeholders, and regulators consider when designing and implementing reforms to energy and ancillary services markets to increase operational flexibility?

4. What are the tradeoffs to consider in procuring flexibility in the energy and ancillary services markets versus the capacity market or another new shorter-term forward market construct?

II. Comments on Supplemental Notice for October 12, 2021 Technical Conference

We are seeking comments on the topics discussed during the technical conference held on October 12, 2021, including responses to the questions listed in the Supplemental Notice issued in this proceeding on October 7, 2021 in accordance with the deadlines and other guidance above. The questions from the agenda are included below.

Panel 1: Incenting Resources to Reflect Their Full Operational Flexibility in Energy and Ancillary Services Offers

1. Do any existing RTO/ISO energy and ancillary services market participation rules, supply offer rules, eligibility requirements, and relevant procedures encourage certain resources to offer into the market inflexibly (i.e., without reflecting the full range of their physical operating capabilities)? For example, are any changes to resource supply offer rules or uplift eligibility requirements needed to ensure resources submit physical offer parameters (e.g., notification time, minimum run time, ramp rates) that reflect their flexible capabilities? To what extent do RTOs/ISOs account for existing fuel limitations, like natural gas supplies, that have the potential to impact resource flexibility?

2. Do any existing RTO/ISO energy and ancillary services market rules exhibit an undue preference for certain resource types over other resource types? If so, please explain how and provide examples.

3. To what extent do existing self-scheduling or self-commitment rules in RTO/ISO markets reduce the amount of operational flexibility available to the RTO/ISO in real time and the system's need for operational flexibility? Are options for self-scheduling and self-commitment needed to allow resource owners to make the best use of their assets over time?

4. Do current RTO/ISO offer rules, market power mitigation practices, and reference levels prevent or discourage resources from including in their offers the additional costs, if any, that resources incur from being more flexible (e.g., longer-term wear

and tear on natural gas resources due to increased cycling, battery warranty considerations, etc.)? Are such costs difficult to quantify? If so, please explain why. How should RTOs/ISOs review such costs to ensure that resources' energy and ancillary services supply offers are competitive?

Panel 2: Maximizing the Operational Flexibility Available from New and Emerging Resource Types

1. Do existing RTO/ISO energy and ancillary services market rules, practices, or procedures prevent or otherwise obstruct relatively new and emerging resource types from fully participating in RTO/ISO markets and offering the operational flexibility they are technically capable of providing?

2. To what extent do existing RTO/ISO energy and ancillary services market rules require standalone variable energy resources to respond to dispatch instructions (e.g., curtailment)?

    a. To what extent are standalone variable energy resources technically capable of being "dispatchable?" Is there a distinction between being dispatched down and being curtailed?

    b. Under what circumstances can a standalone variable energy resource be dispatched up versus down?

3. To what extent do resource capabilities vary amongst different classes and vintages of variable energy resources (e.g., newer vs. older wind turbine models, onshore vs. offshore wind, fixed-tilt vs. tracking solar, etc.) and do offer rules currently reflect such differences, if any?

4. To what extent are emerging resource types, such as hybrids, storage resources, and distributed energy resource aggregations technically capable of providing existing ancillary service products or other reliability services? Acknowledging that some market rules are evolving due to Order Nos. 841[8] and 2222,[9] do current RTO/ISO market rules for ancillary services and other reliability services, such as eligibility requirements, align with these emerging resource types' capabilities?

5. What RTO/ISO energy and ancillary services market reforms could be adopted, if any, to ensure that new and emerging resource types are able to offer their full operational capabilities into RTO/ISO energy and ancillary services markets to help operators manage changing system needs?

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[8] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 83 FR 9580, 162 FERC ¶ 61.127

[9] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 85 FR 67094, 172 FERC ¶ 61,247

a. Would shortening the day-ahead market interval length increase the operational flexibility available from resources? What considerations (e.g., computing time) are important to consider when establishing the length of energy and ancillary services market intervals?

b. RTOs/ISOs often require resources that provide ancillary services to be capable of doing so for a duration of 60 minutes. Does this eligibility requirement limit the pool of resources available to offer ancillary services into RTO/ISO markets? Would reexamining the need for this particular eligibility requirement present reliability concerns or raise other issues for operators? If so, please explain.

Panel 3: Revising RTO/ISO Market Models, Optimization, and Other Software Elements to Address Operational Flexibility Needs

1. What are the challenges to incorporating uncertainty within the current RTO/ISO market software? For example, how can improvements in forecasting, the use of intra-day commitment processes that include a range of forecasts, or longer look-ahead commitment and dispatch horizons result in more efficient unit commitment and dispatch in real time?

2. Can changes to RTO/ISO unit commitment and dispatch software address the need to posture system resources optimally to meet expected and unexpected ramp and operational flexibility needs?

    a. How are these enhancements tailored to the expected magnitude of forecast errors in different time periods?

    b. How would multi-period dispatch modeling in the real-time market help address operational flexibility needs? What are the advantages and disadvantages of a binding as opposed to an advisory multi-period dispatch model?

    c. What are the computational burdens associated with such modeling enhancements?

3. To what extent can software enhancements for modeling specific technology types (e.g., multi-configuration modeling of combined cycle units, storage, etc.) help address the system's changing operational needs?

4. Can multi-day-ahead markets or hour-ahead markets help address operational flexibility needs in RTOs/ISOs? What is the objective of such approaches, and are there potential drawbacks?

Panel 4: Out-of-Market Operator Actions Used to Manage Net Load Variability and Uncertainty

1. RTO/ISO reports and filings to the Commission indicate that at times operators take out-of-market actions to address net load uncertainty. What impacts do such actions have on price formation in RTO/ISO energy and ancillary services

markets? How strong are those impacts, both in terms of individual instances of operator actions and in terms of more general effects on the efficiency of the markets?

2. Do RTOs/ISOs anticipate that, without RTO/ISO market reforms, out-of-market operator actions will increase over time in response to changing system needs?

3. To what degree, if any, do out-of-market actions by operators undermine RTO/ISO energy and ancillary services market reforms, such as operating reserve demand curve reforms or ramp products, designed to incent resources to provide RTO/ISO operators with the operational flexibility needed to manage the system?

4. How can RTOs/ISOs best mitigate the risks of out-of-market operator actions undermining incentives for resource operational flexibility, to the extent such risks exist?

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Kimberly D. Bose,
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